

METRIC DEPENDENCE OF PV ECONOMICS

Easan Drury
National Renewable Energy Laboratory
1617 Cole Blvd
Golden, CO 80401
easan.drury@nrel.gov

Paul Denholm
National Renewable Energy Laboratory
1617 Cole Blvd
Golden, CO 80401
paul.denholm@nrel.gov

Robert Margolis
National Renewable Energy Laboratory
901 D. Street SW, Suite 930
Washington, D.C., 20024
robert.margolis@nrel.gov

ABSTRACT

Photovoltaic (PV) systems are installed by several types of market participants, ranging from residential and commercial customers that buy or lease systems for their roofs, to large-scale system developers building several megawatt ground-mounted systems. The relative returns on a PV investment can be very different for each market participant. This is partially driven by fundamental differences in PV prices, incentives, financing options, and the value of PV electricity generated in wholesale or retail markets. It can also be driven by the use of different economic performance metrics to characterize PV value. Here, we evaluate the relative performance of PV investments using several economic performance metrics, including payback time(s), net present value, profitability index, benefit to cost ratio, internal rate of return, monthly bill savings, and the levelized cost of electricity. We evaluate the relative PV performance for each metric over a range of system characteristics, including PV price, performance, financing and market conditions. Lastly, we highlight the potential unintended consequences of policy design based on the different, metric-driven PV returns seen by each market participant.

1. INTRODUCTION

The modularity of PV systems has led to several types of market participants developing PV projects, ranging from residential and commercial customers that buy or lease small (few to tens of kW) rooftop systems, to utility-scale PV developers that install large (>1 MW) ground-mounted systems. Each market participant typically looks for different types of returns from a PV investment. For

example, residential customers frequently use payback times or monthly electric bill savings to evaluate a PV or energy efficiency investment [1,2,3]. Commercial customers frequently use the net present value (NPV), profitability index (PI) [4], benefit to cost (B/C) ratio, or the internal rate of return (IRR) [5]. Vertically integrated utilities or independent power producers may use the levelized cost of electricity (LCOE) to rank a PV development project relative to other potential investments [6].

Each PV market participant will see different returns from a PV investment. These are driven both by fundamental differences in PV prices and revenues available to each participant, and from the use of different economic performance metrics to characterize investment returns. For example, large PV systems (>1 MW) are frequently developed at a far lower costs (per unit capacity) than small residential or commercial rooftop systems. However, the electricity produced by large PV systems will frequently be valued at, or near, wholesale electricity rates through a power purchase agreement (PPA) with the local utility, while rooftop PV systems will offset electricity use in the retail market at rates that are frequently twice as high as wholesale rates [7].

In addition to the different PV price and performance characteristics, the perceived value of a PV investment is also dependent on the economic performance metric(s) used to characterize PV returns. For example, a large PV system developer may use the relationship between the project LCOE and the PPA rate offered by a local utility to value a PV investment, while a residential customer may use their projected monthly bill savings or a PV payback time to evaluate the investment. Even if PV price and performance

characteristics were identical, the use of different metrics could encourage the residential customer invest but discourage the large PV developer, or vice versa.

This study focuses on how the use of different economic performance metrics affects the perceived value of a PV investment, and highlights the potential unintended consequences of policy design.

2. ECONOMIC PERFORMANCE METRICS

Table 1 summarizes different economic performance metrics that are frequently used to inform PV investment decisions.

TABLE 1: ECONOMIC METRICS COMMONLY USED TO CHARACTERIZE PV PERFORMANCE

Metric	Equation
Net Present Value (NPV)	$NPV = \sum_{t=0}^N \frac{Revenue_t - Cost_t}{(1+d)^t}$
Profitability Index (PI)	$PI = \frac{\sum_{t=0}^N \frac{Revenue_t - Cost_t}{(1+d)^t}}{Investment\ Cost}$
Benefit to Cost (B/C) ratio	$BCR = \frac{\sum_{t=0}^N \frac{Revenue_t}{(1+d)^t}}{\sum_{t=0}^N \frac{Cost_t}{(1+d)^t}}$
Internal Rate of Return (IRR)	$IRR : NPV = \sum_{t=0}^N \frac{Revenue_t - Cost_t}{(1+IRR)^t} = 0$
Modified Internal Rate of Return (MIRR)	$MIRR = \sqrt[n]{\frac{Future\ Value(positive\ cash\ flows,\ re - investment\ rate)}{-Present\ Value(negative\ cash\ flows,\ finance\ rate)}} - 1$
Payback Time	$Simple\ Payback = \frac{PV\ Price - Federal\ ITC}{Annual\ PV\ Revenue - O \& M}$ $TNP\ Payback : \sum_{t=0}^{TNP\ Payback} Cashflow_t > 0$ $IRR\ Payback : (1+IRR)^{IRR\ Payback} = 2$
Levelized Cost of Electricity (LCOE)	$LCOE = \frac{\sum_{t=0}^N \frac{Cost_t}{(1+d)^t}}{\sum_{t=1}^N \frac{Electrical\ Energy_t}{(1+d)^t}}$

Several economic performance metrics have one clear definition, like NPV or LCOE. However, other metrics like payback time can have several commonly used definitions [8]. We include three payback metrics in this analysis: 1) simple payback time, defined as the time required for undiscounted PV revenues to equal the undiscounted capital cost [9]; 2) time to net positive cash flow payback (TNP payback), defined as the time required for PV revenues to

exceed the cost of ownership [10]; and 3) IRR-based payback times, defined as the time required for an investment accruing at a rate equal to the system IRR to double in value [11].

Different customer types use different economic performance metrics largely because they are looking for different types of returns on their investments. For example, a residential home owner may be interested in short payback times because they are uncertain how long they will remain in their house, and are uncertain about how a PV investment will affect their home value. Commercial customers may be interested in characterizing the annualized return on a PV investment—using B/C ratios, PIs, or IRRs/MIRRs—to help them rank a PV investment relative to other investment opportunities. Large PV developers may be interested in several performance metrics, including LCOE to rank the cost of PV electricity relative to a PPA offering, or additional metrics like B/C ratio, NPV, and others to rank the performance of a PV investment relative to other investment opportunities.

3. PV CASH FLOWS

We start by evaluating reference PV performance for each economic performance metric, using the PV price, performance, financing and market assumptions listed in Table 2. We then vary several PV system characteristics to capture the relative sensitivity of PV performance using each metric. With the exception of tax structures and incentives, we assume the same PV price and performance characteristics for all PV systems in the reference case to focus on how the choice of economic performance metric affects the perceived value of a PV investment. We evaluate PV performance over a wide range of system prices and financing parameters in the sensitivity analysis, and some of these system characteristics may better represent PV price and performance in different markets than the reference parameters.

TABLE 2: REFERENCE PV SYSTEM PARAMETERS

Effective PV Price ¹	\$4,000/kW
Capacity Factor ²	17%
Annualized Electricity Rate	15 ¢/kWh
PV Degradation	0.5%/year
Down Payment	20%
Loan Rate (real)	5%
Loan Term	20 years
Capital Re-investment Rate ³ (real)	8%
Discount Rate ⁴ (real)	5%
Incentives	30% federal ITC; MACRS depreciation for commercial and utility-scale developers
Net Metering	Full

Annualized O&M payment	\$35/year first 10 yr \$25/yr for next 10 yr \$20/yr for final 10 yr
Analysis Term	30 years
Tax Implications	After tax energy payments for residential; Before tax energy payments for commercial systems

¹Effective PV price includes state and local PV incentives, but not the 30% federal ITC.

²A 17% PV capacity factor represents PV output from a fixed tilt (tilt=latitude) residential PV system in Kansas City, MO [12]. Similar PV systems are likely to perform better in some locations (21.5% capacity factor in Phoenix, AZ) or worse in others (15.5% capacity factor in Chicago, IL) [12].

³The capital re-investment rate is used to calculate MIRR, and represents the company's opportunity cost of capital.

⁴We assume a discount rate equal to the loan rate in the reference scenarios to avoid introducing a time value for borrowed money.

We assume that all PV systems are debt financed, and receive the 30% federal ITC (directly for customer owned systems, and indirectly as a reduced system cost for third party owned systems). PV systems installed by for-profit commercial entities can also depreciate the value of the PV asset following the 5-year Modified Accelerated Cost Recovery System (MACRS) depreciation schedule. The upfront payment of tax incentives significantly impacts PV returns for some, but not all, economic metrics.

In addition to the customer-owned system parameters in Table 2, we estimate third-party owned system parameters by assuming lower financing costs (3% real interest rate), shorter loan/lease terms (15 years), and lower relative PV costs (25% less than customer owned systems). These parameters are used to characterize the monthly bill savings that could be offered by the leasing company to a customer, and we use bill savings as a proxy to compare the relative economics and sensitivities of leased PV systems to customer owned systems. There is a large range in historical lease offerings, based on local PV incentives and PPA offerings by the local utility [13], and the reference parameters are within the range of historical offers.

Figure 1 shows annual after-tax PV cash flows generated using the reference assumptions in Table 2. PV costs are primarily composed of the initial down payment, followed by annual loan payments and O&M costs. These costs are partially offset by system tax benefits, including the tax-deductible payments on loan interest and MACRS depreciation for commercial customers. PV revenues are based on the combination of PV output and the value of PV electricity, which can be challenging to quantify because electricity rates frequently depend on the time of day or season (time of use rates), and customer demand (tiered rates for residential customers, demand-based rates for commercial customers). Additionally, PV revenues are

frequently impacted by state and local net metering policy¹. We approximate PV revenues by defining an annual mean PV capacity factor² and an annualized effective electricity rate that represents the mean value of PV-generated electricity.

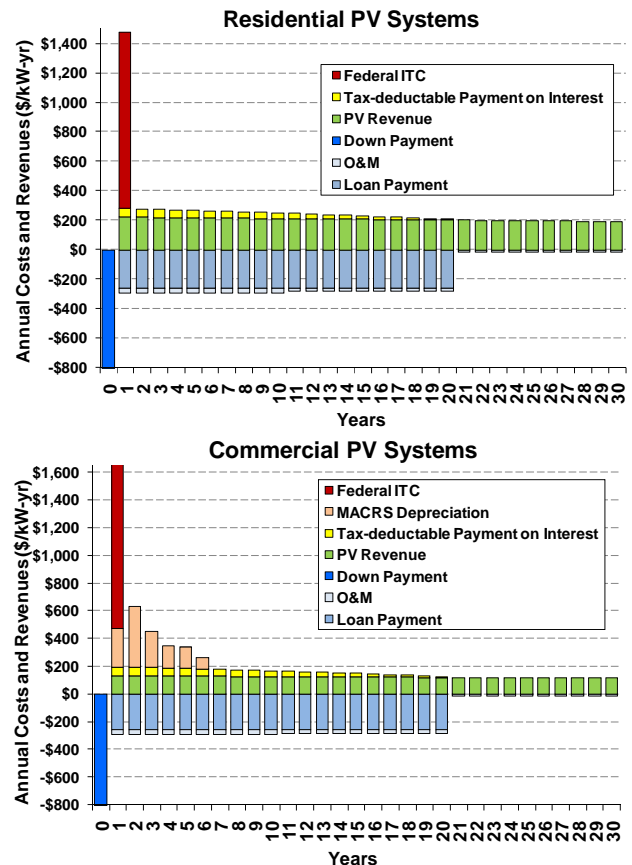


Fig. 1: Residential and commercial PV system costs, revenues, and tax benefits.

Figure 1 shows that the largest annual PV costs (down payment) and tax incentives (federal ITC and MACRS) occur in the first few years of system ownership. After this, the reference PV costs and revenues are nearly identical leading to small net revenues or net costs each year. The up-front nature of PV costs and incentives has a significant

¹ Net metering is a market mechanism that sets the value of PV generation that exceeds electricity use. In areas with full net metering, excess PV electricity is purchased by local utilities at retail electricity rates. Other areas have partial net-metering policies where excess PV generation is valued similar to wholesale electricity rates that roughly capture the value of offsetting fossil fuel use. Other areas have no net-metering policy, and excess PV generation is given to the utility for no cost.

² PV capacity factors represent the amount of alternating current (AC) electricity generated by a given amount of direct current (DC) PV capacity, where Capacity Factor = Annual Electricity Generation / (8760 * System Capacity).

impact on some economic performance metrics (IRR and TNP payback), but not others (LCOE, simple payback).

4. RESULTS

Different economic performance metrics frequently show different price and performance thresholds for when a PV investment begins to look attractive. Here, we evaluate relative PV performance over a range of system parameters.

4.1. PV Price

Figure 2 shows relative PV performance for several economic metrics, calculated for a range of effective PV prices from \$1,000 - 7,000/kW³. Effective PV prices represent the total installed system price after taking state and local incentives, but before taking the 30% federal ITC. These effective prices represent the range of PV prices currently seen by U.S. customers, which are subject to a wide range in state and local PV incentives offered in the form of rebates (ranging from \$500-4,000/kW in Maryland and Florida), and tax incentives (ranging from 10-50% of system costs in Kansas and Louisiana) [14].

The economic performance metrics used to characterize a PV investment returns can be categorized into those that show a nearly linear response to PV prices—NPV, monthly bill savings, MIRR, simple and MIRR-based payback times, and LCOE—and those that show non-linear responses to changing prices—IRR, B/C ratio, PI and TNP payback. This distinction is important because several of the non-linear economic performance metrics show strong performance thresholds. For example, the IRR metric shows a 4% return for a \$4,800/kW residential PV system, and over a 30% return on a \$4,400/kW system. Commercial PV systems show more dramatic IRR thresholds because of the upfront nature of MACRS capital depreciation (Figure 1) in addition to the 30% federal ITC. TNP payback times also show strong threshold behavior.

Each economic performance metric shows a different price threshold for when a PV investment begins to look attractive. For example, NPVs become positive for \$4,700/kW residential PV systems and \$6,000/kW commercial PV systems. However, monthly bill savings do not become positive until PV system prices are lower than \$4,000/kW, and PV LCOEs do not reach retail electricity rates until PV systems prices are lower than \$3,000/kW. System NPVs look more attractive than system LCOEs at higher PV prices because NPVs are sensitive to the timing

of PV revenues and cost streams, whereas LCOEs are only affected by the timing of costs.

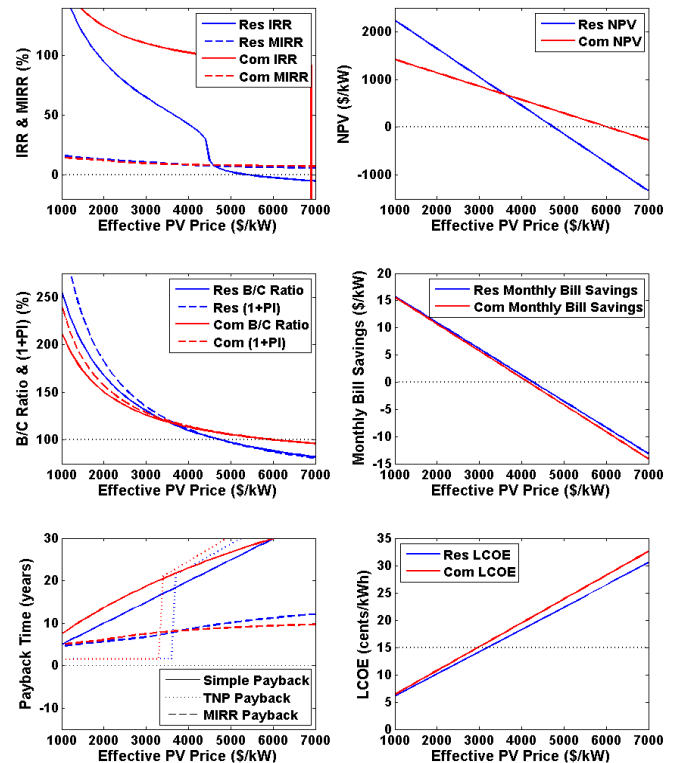


Fig. 2: PV economic performance characterized using several metrics for a range of capital costs, for both residential (blue) and commercial (red) systems. The profitability index (PI) is shifted by adding one (1+PI) to better compare PI performance with B/C ratios.

The difference in PV price thresholds between metrics could significantly impact how potential PV customers perceive the value of a PV investment. For example, a commercial customer may be interested in investing in a \$6,000/kW PV system if they use a NPV>0 criteria in their investment decision. However, a large PV developer may require effective PV prices to be less than \$3,000/kW for the project LCOE to be equal to, or less than, the retail electricity rate (or similar PPA offer). In this case, the choice of economic performance metric could have as much impact on the investment decision as decreasing (or increasing) PV prices by a factor of two. This is similarly true for other economic metrics, as shown by the large differences in prices required for IRRs, MIRR, B/C ratios, monthly bill savings and payback metrics to begin looking attractive.

4.2. Non-Price Economic Drivers

Non-price system characteristics can significantly impact PV economic performance. However, the relative

³ Here and elsewhere, all costs and revenues are given in units of 2011 U.S. dollars. Cost and revenue projections are given in real, not nominal, dollars.

sensitivities to non-price characteristics are frequently inconsistent across metrics.

4.2.1. Threshold-driven Metrics

The relative timing of PV costs and revenues are critically important for some metrics like IRR and TNP payback times. Here, we evaluate how financing, PV performance and market characteristics lead to threshold behavior.

Figure 3 shows the impact of non-price system characteristics on PV payback times (simple payback and time to net positive cash flow (TNP) payback). Simple payback times are insensitive to system financing parameters, and show smooth monotonically decreasing relationships to increasing electricity rates and capacity factors. Simple payback times are longer than 10 years for the full range of system assumptions, and a \$4,000/kW PV system is not likely to look attractive to the majority of customers using this metric [15].

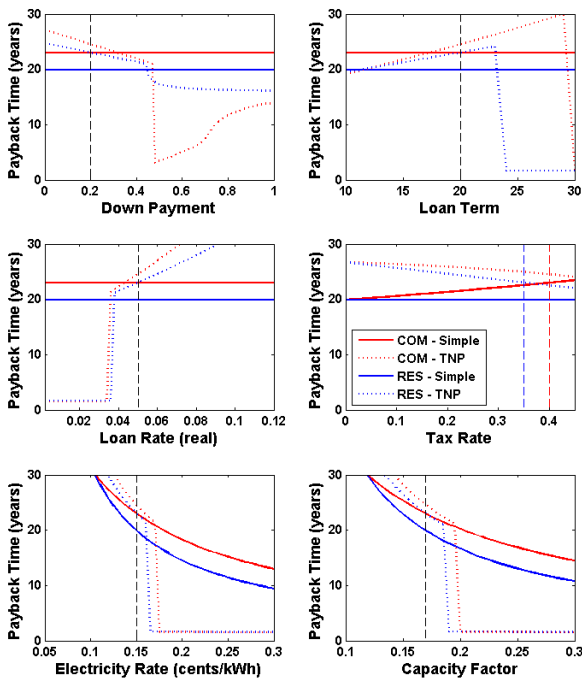


Fig. 3: Payback times for \$4,000/kW residential and commercial PV systems over a range of financing, performance, and market parameters. Both simple and time to net positive cash flow (TNP) payback times are shown for commercial and residential systems.

TNP payback times are similar to simple payback times for the reference system assumptions, but are much more sensitive to varying system parameters and show discontinuous performance thresholds. For example, decreasing the loan interest rate from 4% to 3% (real, not

nominal) decreases payback times from over 20 years to less than two years. This is because the cost of the system down payment is offset by the 30% federal ITC after the first year of ownership, leading to a positive net cash flow after the first year. If the loan rate is 4% (real), the loan payments and O&M costs are higher than system revenues, leading to a slightly negative cash flow by the end of the loan term (20 years). If the loan rate is reduced to 3% (real), PV revenues are higher than loan payments and O&M costs for most of the loan term, and system net revenues remain positive from the end of the first year on. This discontinuous nature of the TNP payback times is seen for several system parameters that affect the timing of PV costs (down payment fraction, loan term) and increase PV revenues (electricity rates and capacity factors). In most cases, the threshold behavior shifts TNP payback times from over 20 years to less than a few years for small changes in input assumptions.

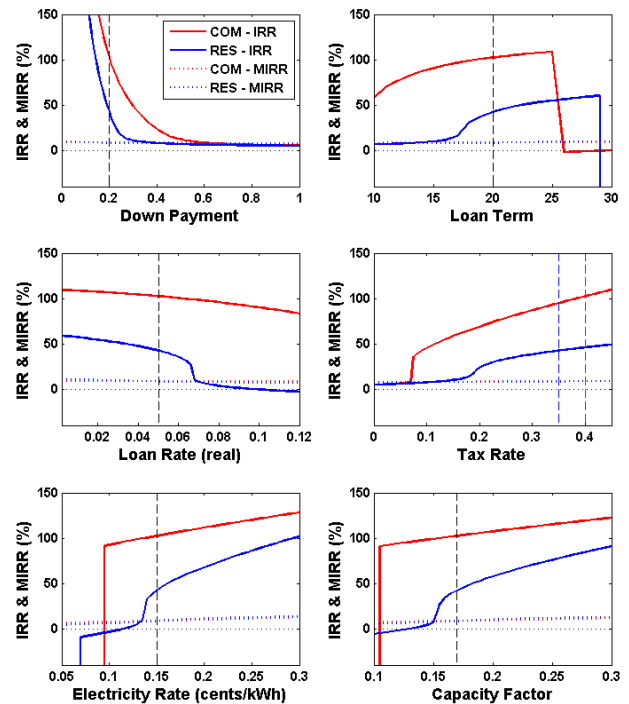


Fig. 4: Internal rate of return (IRR) and modified internal rate of return (MIRR) for \$4,000/kW residential and commercial PV systems over a range of financing, performance, and market parameters.

Figure 4 shows PV IRRs and MIRR for commercial and residential systems. Both commercial and residential IRRs show strong threshold behavior, primarily because annual PV cash flows oscillate between negative (system down payment), to positive (federal ITC and MACRS for commercial systems), to negative (loan payment plus O&M costs exceed system revenues), to positive (PV revenues after the loan term has ended). This threshold behavior is particularly strong for U.S. systems because of the upfront

nature of the federal ITC and MACRS depreciation, and not as strong for systems with production-based incentives [5].

Commercial IRRs are typically much higher than residential IRRs because the upfront nature of MACRS depreciation (Figure 1) has a larger impact on system IRRs than the decrease in revenue (commercial energy costs are tax deductible, decreasing the value of PV electricity). IRRs are very sensitive to variables that affect the timing of PV costs and revenues, seen by the sensitivity to financing terms and tax rates. IRRs are less sensitive to parameters that affect mean system costs (loan rates) or system revenues (electricity rates, and capacity factors).

The sensitivity of IRRs to the down payment fraction is particularly important because commercial companies have a wide range of debt-to-equity ratios, both within and across industries. A company's debt-to-equity ratio can also change over time. The 20% down payment assumption corresponds to a relatively high debt-to-equity ratio of 4. A common commercial debt-to-equity ratio is 1.5, and the resulting 40% down payment fraction reduces IRRs to about 20%.

We find similar IRR relationships to those found in previous studies [5, 10]. However, IRR performance in this analysis is far more driven by threshold behavior because U.S. systems typically have several up front incentives like the 30% federal ITC, and MACRS capital depreciation. Since these tax benefits offset costs early in the investment, they tend to make positive IRRs very positive [16], and exacerbate threshold behavior. We find a significantly higher impact of tax rates on PV IRRs than shown by *Talavera et al.* [5], because tax rates directly scale MACRS depreciation in the U.S. Unlike previous studies, we find that the strong threshold behavior of PV IRRs make them a poor metric for characterizing the returns on a PV investment.

MIRRs have been proposed as a better metric for characterizing investment returns than IRR [16]. However, the upfront nature of PV down payments and tax incentives reduce the sensitivity of MIRRs to the range of variables explored, and we find that MIRRs are dominated by the assumed reinvestment rate (8%). For example, the reference commercial MIRR is 8.7%. This MIRR increases to 9.9% if the annualized electricity rate is increased from \$0.15/kWh to \$0.20/kWh, and increases to 12.6% if electricity rates are increased to \$0.30/kWh. MIRRs also show a similarly small increase for decreasing PV prices (Figure 2). These, and other, changes in PV price and performance characteristics have a far greater impact on the other economic performance metrics. The lack of MIRR responsiveness to shifting input parameters, and the strong dependence of MIRRs on the assumed re-investment rate (because of the

upfront nature of costs and incentives) decreases the utility of MIRRs for characterizing the value of a PV investment.

4.2.2. Smoothly-varying Metrics

Figure 5 shows annualized monthly bill savings for residential and commercial PV customers. Monthly bill savings show smoothly varying, monotonically increasing or decreasing sensitivities to the range of system parameters explored. Monthly bill savings increase most with increasing loan terms (and corresponding lease terms) and increasing revenue streams (increasing electricity rates and capacity factors). Monthly bill savings are less sensitive to varying tax rates.

Monthly bill savings are positive for the reference conditions (\$1.26/kW-month for residential and \$0.73/kW-month for commercial systems). The actual monthly bill savings received by a customer is based on the PV system size. Residential PV systems are typically about 5 kW and commercial systems are around 100 kW, leading to annual bill savings of \$76/yr for residential customers and \$878/yr for commercial customers.

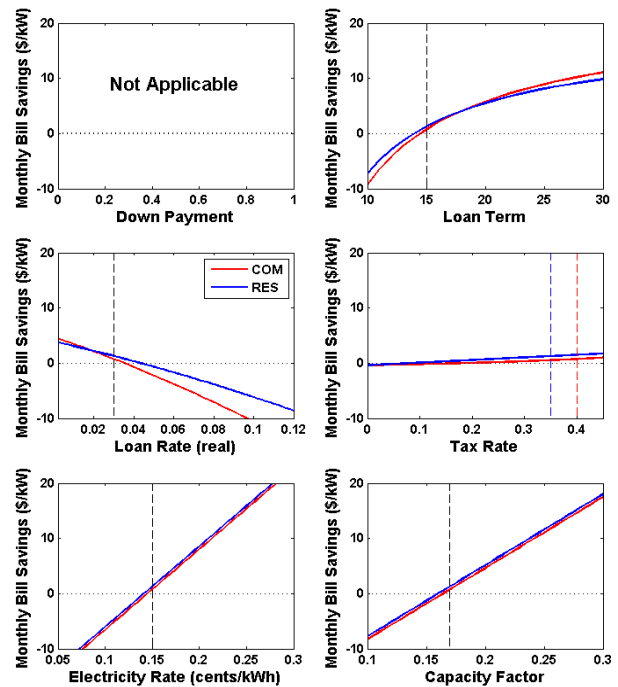


Fig. 5: Annualized monthly bill savings, given in units of \$/kW of PV capacity, for residential and commercial PV systems.

The reference PV cost and performance parameters for third party systems represent monthly bill savings that are likely to be attractive to a customer. However, similar reference parameters led to PV payback times that were greater than

20 years, and are not likely to be attractive to the majority of customers. This is partially due to the lower PV costs assumed for third party sellers (based on reducing the depth and cost of the PV supply chain) and lower financing rates (better access to low cost capital), but is also caused by the different dynamics of the monthly bill savings metric as compared to payback times. This suggests that if the reference parameters are met, there is the potential for robust market growth for third-party owned systems but not for customer owned systems if they use payback time to inform investment returns. However, the performance gap between monthly bill savings and TNP payback times decreases considerably for lower effective PV prices, lower loan rates, or higher revenues (increasing capacity factors and electricity rates) because of the threshold nature of the TNP payback metric.

Figure 6 shows the sensitivity of residential and commercial LCOEs to the range of PV financing, market and performance assumptions. The assumed retail electricity rate of \$0.15/kWh is shown in all figures except for the electricity rate figure, where the reference line tracks the increase in electricity rates. LCOEs show smoothly varying, monotonically increasing or decreasing sensitivities to the range of financing, market and performance parameters. While LCOEs are unaffected by PV revenue streams, LCOEs become closer to, or less than retail electricity rates as rates increase.

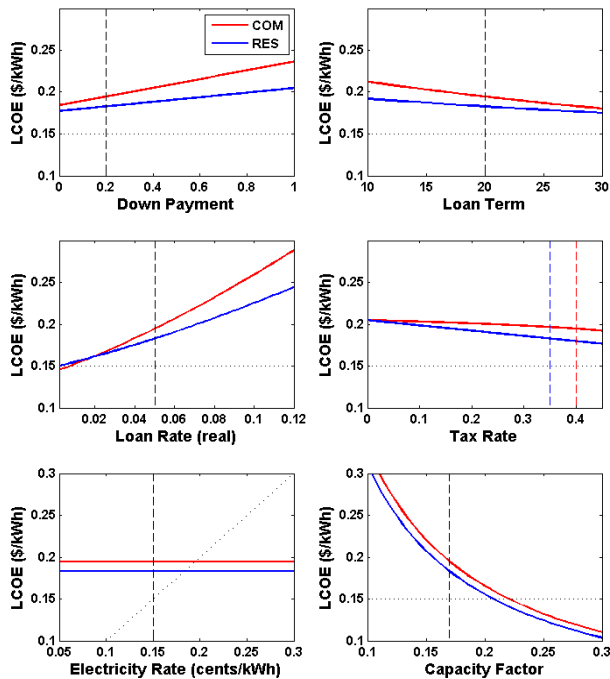


Fig. 6: Levelized Cost of Electricity for \$4,000/kW residential and commercial PV systems over a range of financing, performance, and market parameters.

PV LCOEs are higher than the assumed retail electricity rates for the reference assumptions and for several variations in parameters. LCOEs are not particularly sensitive to the timing of PV costs and revenues (financing terms and tax rates). LCOEs are more sensitive to the system capacity factor, where a 21% residential capacity factor and a 22% commercial capacity factor allow PV LCOEs to reach retail rates. For comparison, a fixed tilt (tilt=latitude) residential PV system located in Phoenix, AZ could reach a 21.5% capacity factor [12].

However, as mentioned previously, NPVs typically become positive for PV prices far below when LCOEs reach retail electricity rates, based on the timing of system costs and revenues. Because of this, customers using LCOEs may be less inclined to invest in PV than customers using different economic performance metrics. Additionally, comparing PV LCOEs with mean electricity rates can significantly underestimate the value of PV electricity in regions with time of use rates, tiered rates, or demand-based rates [17].

One challenge in comparing relative PV performance across different metrics is that each metric typically uses different units to characterize returns. These include years for payback times, annualized returns for IRRs, dollar amounts for NPV, and the cost of electricity for LCOEs. While we can evaluate the unique sensitivities in PV performance across a range of system parameters and define performance thresholds, we cannot compare relative sensitivities exactly because they are measured in different units.

5. CONCLUSIONS

The PV market has several market participants that frequently use different economic performance metrics when evaluating a potential PV investment. We show that the perceived value of a PV investment can be highly metric dependent, and the relative inconsistency in PV returns across metrics could significantly affect the growth of different market segments.

We show that the effective price required for a PV investment to look attractive (e.g. $NPV > 0$) can be very different for each economic performance metric. In some cases, the choice of metric could impact the investment decision by as much as increasing (or decreasing) the effective PV price by a factor of two. The relative sensitivity of PV performance to non-cost drivers also shows strong metric-dependence. The IRR and time to net positive cash flow (TNP) payback metrics show strong threshold behavior, and are very sensitive to the timing of PV costs and revenues. Other metrics, like monthly bill savings and

LCOEs are less sensitive to the relative timing of system costs and revenues, and do not exhibit threshold behavior.

The metric dependent nature of PV performance has strong implications for successful policy design. Even if PV cost and performance characteristics were identical across markets, we show that the use of different economic performance metrics can make a PV investment look profitable in one market (e.g. commercial customers using NPV or PI) for the reference conditions, and not in other markets (e.g. large system developers using LCOE). Additionally, different incentive types are likely to have very different impacts on PV performance. For example, the upfront nature of the 30% federal ITC disproportionately increases system IRRs and TNP payback times relative to monthly bill savings, NPV, and other metrics. Access to low-cost, long term financing would similarly improve IRRs and TNP payback times by more than other smoothly varying metrics. Understanding both the differences in relative price thresholds and the relative sensitivity to changing system parameters is necessary for developing targeted, efficient demand-side policy.

6. ACKNOWLEDGMENTS

We thank Karlynn Cory, David Feldman, James Milford, Paul Schwabe, Walter Short and Bethany Speer for comments and input.

7. REFERENCES

- [1] Kastovich J., R. Lawrence, R. Hoffmann, C. Pavlak, 1982. Advanced Electric Heat Pump Market and Business Analysis. Oak Ridge National Laboratory, ORNL/Sib/79-2471/1.
- [2] Perez R., L. Burtis, T. Hoff, S. Swanson, and C. Herig, 2004. Quantifying residential PV economics in the US – payback vs cash flow determination of fair energy value. *Solar Energy*, 77, 363-366.
- [3] Sidiras, D.K., and E.G. Koukios, 2005. The effect of payback time on solar hot water systems diffusion: the case of Greece, *Energy Conversion and Management*, 46, 269-280.
- [4] Chabot B., 1998. From Cost to Prices: Economic Analysis of Photovoltaic Energy and Services, *Prog. Photovolt. Res. Appl.*, 6, 55-68.
- [5] Talavera D.L., G. Nofuentes, and J. Aguilera, 2010. The internal rate of return of photovoltaic grid-connected systems: A comprehensive sensitivity, *Renewable Energy*, 35, 101-111.
- [6] Sunpower Corp., 2008. The Drivers of the Levelized Cost of Electricity for Utility-Scale Photovoltaics, Sunpower Corporation, San Jose, CA. August 2008, http://us.sunpowercorp.com/downloads/SunPower_levelized_cost_of_electricity.pdf, accessed 3/2011.
- [7] EIA (Energy Information Administration), 2011. Annual Energy Outlook 2011 with projections to 2035, Early Release, Report no. DOE/EIA-0383ER (2011). <http://www.eia.doe.gov/forecasts/aeo/>, accessed 3/2011.
- [8] Duffie, J.A., and W.A. Beckman, 2006. *Solar Engineering of Thermal Processes*. Third Edition, John Wiley & Sons, Inc., Hoboken, New Jersey. 908 pp.
- [9] Paidipati J., L. Frantzis, H. Sawyer, A. Kurrasch, 2008. Rooftop Photovoltaics Market Penetration Scenarios. National Renewable Energy Laboratory Subcontract Report, NREL/SR-581-42306.
- [10] Audenaert, A., L. De Boeck, S. De Cleyn, S. Lizin, and J-F. Adam, 2010. An economic evaluation of photovoltaic grid connected systems (PVGCS) in Flanders for companies: A generic model, *Renewable Energy*, 35, 2674-2682.
- [11] EIA (Energy Information Administration), 2008. Commercial Sector Demand Module of the National Energy Modeling System: Model Documentation 2008, Energy Information Administration, DOE/EIA-M066(2008).
- [12] SAM (Systems Advisor Model) 2011. SAM version 2010.11.9, National Renewable Energy Laboratory, <https://www.nrel.gov/analysis/sam/>, accessed 3/2011.
- [13] NREL (National Renewable Energy Laboratory) 2009, Solar Leasing for Residential Photovoltaic Systems, National Renewable Energy Laboratory Fact Sheet, NREL/FS-6A2-43572, <http://www.nrel.gov/docs/fy09osti/43572.pdf>, accessed 2/2011.
- [14] DSIRE (Database of State Incentives for Renewables and Efficiency) 2011. <http://www.dsireusa.org>, accessed 3/2011.
- [15] Drury, E., P. Denholm and R. Margolis, (2010). Modeling the U.S. Rooftop Photovoltaics Market, National Renewable Energy Laboratory, NREL/CP-6A2-47823.
- [16] McKinsey & Co., 2004. Internal Rate of Return: A Cautionary Tale, *The McKinsey Quarterly*, October, 20, 2004.
- [17] Borenstein, S., 2008. The Market Value and Cost of Solar Photovoltaic Electricity Production, University of California Energy Institute, Center for the Study of Energy Markets, CSEM WP 176.